**TECHNICAL REVIEW AND EVALUATION
OF APPLICATION FOR
AIR QUALITY PERMIT NO. 1000107**

I. INTRODUCTION

The Yucca Power Plant, located just to the northwest of Yuma, is jointly owned by Arizona Public Service Company (APS) and Imperial Irrigation District (IID). The Yucca plant provides power to the electric grid on an as-needed-basis, primarily during summer months when air conditioning power demands are high.

The Yucca plant was built in 1959 originally as a steam electric generating plant with a capacity of 75,000 KW. Five combustion turbines were later added in 1970's to meet the demands of the plant's growing customer base. Yucca currently has the capacity to generate 250,000 KW. Yucca has two sources of fuel: natural gas and fuel oil. Natural gas for the steam unit and the combustion turbines is supplied by pipeline. Fuel oil is delivered to the plant by railroad tank cars or trucks and stored in tanks with a capacity of 346,000 barrels.

A. Company Information

Facility Name: Yucca Power Plant
Mailing Address: 7522 S. Somerton Avenue, Yuma, Yuma County, AZ 85364
Facility Address: 7522 S. Somerton Avenue, Yuma, Yuma County, AZ 85364
Responsible Official: Scott Takinen

B. Attainment Classification

The source is in an attainment area for TSP, SO_2, CO, Ozone, and NO_2. The source is in a nonattainment area for PM-10.

C. Process Rate and Operating Hours

The maximum process rates and operating hours of the significant points of emissions at Yucca are summarized in the following table:

Table 1: Maximum Process Rates

Unit	Hours	MW/hr	MW-hr/yr
Steam Unit #1	8760	80	700800

Unit	Hours	MW/hr	MW-hr/yr
Turbine #1	8760	22	192720
Turbine #2	8760	22	192720
Turbine #3	8760	67	586920
Turbine #4	8760	66	578160
Turbine #21	8760	23.2	203232
Total			2454552

II. COMPANY AND PROCESS DESCRIPTION

Describe primary operating scenario, alternate operating scenarios (if applicable), and include air pollutants from each process. This section will also address Technical Review Questions B.1, B.2, B.3, B.4 and B.6.

Arizona Public Service Company's Yucca Power Plant operates to supply electrical power to the grid on an as-needed basis. Operational flexibility provides the ability to operate the single Steam Unit, and the five Combustion Turbines in any combination as required. The plant also has the flexibility to operate the Auxiliary Boiler to provide heat for fuel oil and maintenance activities.

The Yucca Power Plant currently has the capability to burn natural gas and/or fuel oil. Typical or normal operating scenarios reflect operating the Steam Unit, all five combustion turbines, and the Auxiliary Boiler at a capacity factor of 0 to 100%. Table 2 summarizes the normal and the alternate operating scenarios at the Yucca plant. Data from the emission sources forms shows that Yucca is a major source (for PSD and Title V purposes) of all primary criteria pollutants (except lead) and is a major source of HAPs (formaldehyde and nickel).

Table 2: Operating Scenarios

Source	Normal Operating Scenarios	Alternate Operating Scenarios	Capacity Factor	Operational Flexibility
Steam Unit	Natural Gas		0 - 100%	0 - 100% of Fuel Available
		#4 through #6 grades Fuel Oil	0 - 100%	0 - 100% of Fuel Available
		#4 through #6 grades Fuel Oil and Natural Gas	0 - 100%	0 - 100% of Fuel Available

Combustion Turbines #1,2, and 3	Natural Gas		0 - 100%	0 - 100% of Fuel Available
		#2 Fuel Oil	0 - 100%	0 - 100% of Fuel Available
		#2 Fuel Oil and Natural Gas	0 - 100%	0 - 100% of Fuel Available
Combustion Turbines #4 and 21	#2 Fuel Oil	None	0 - 100%	0 - 100% of Fuel Available
Auxiliary Boiler	Natural Gas		0 - 100%	0 - 100% of Fuel Available
		#4 through #6 grades Fuel Oil	0 - 100%	0 - 100% of Fuel Available
		#4 through #6 grades Fuel Oil and Natural Gas	0 - 100%	0 - 100% of Fuel Available

III. EMISSIONS CALCULATIONS

This section also addresses Technical Remarks Question B.3, B.6 and C.1. Include in the table any additional pollutants applicable to your source. If you have many emission sources, you can list the emissions by area, instead of by individual source.

The Yucca plant has the capability of operating under different scenarios as outlined in Section II of this Technical Remarks document. Sample calculations and emissions from different sources are given here. Typical operating parameters of the turbines, the steam unit and the auxiliary boiler are given in Table 3. Table 4 summarizes the emission factors provided by APS. Table 5 summarizes the emission factors used by the Department to calculate the potential to emit calculations. These emission factors are from AP-42 (1/95 ed.). APS provided their emission factors for the gas turbines and the steam generator from EPA publication EPA 450/4-90-003. These numbers do not vary very much from AP-42 numbers. The differing emission factors are shown in bold face in Tables 4 and 5.

Table 3 Typical Operating Parameters

Description	Steam Unit	Gas Turbines		Auxiliary Boiler
		Units 1, 2, 3 (Frame 5)	Units 4, 21 (Frame 7)	
Average generating capacity (KW)	80,419	19,000	58,000	N/A

Description	Steam Unit	Gas Turbines		Auxiliary Boiler
		Units 1, 2, 3 (Frame 5)	Units 4, 21 (Frame 7)	
Maximum generating capacity (KW)	80,419	22,000	67,000	N/A
Net heat reat at average capacity (Btu/KWh)	10,425	14,482	13,886	N/A
Net heat reat at maximum capacity (Btu/KWh)	10,425	13,966	13,653	N/A
Heating value of natural gas (Btu/scf)	1027	1027	1027	1027
Heating value of fuel oil (Btu/gal)	148,871	138,920	138,920	148,871
Specific gravity, API (oil)	17.6	33.2	33.2	17.6
Density of oil (lb/gal)	7.92	7.17	7.17	7.92

While AP-42 emissions factors from 1/95 are more recent and probably more accurate than the emission factors used by APS, the resulting increases (and decreases in some cases) in calculated emissions do not change the source category status, and do not trigger any new applicable requirements. Therefore, the use of emission factors from EPA 450/4-90-003 to calculate emissions is acceptable. Although calculations have been shown here only for the worst-case scenario of burning fuel oil no. 6 in the steam unit, the unit has the capability to burn fuel oil nos. 4 through 6.

Table 4 Emission Factors (Gas in lb/MMscf and Oil in lb/1000gal. Source: EPA 450/4-90-003)

Pollutants	Steam Unit		Turbines 1, 2, 21		Turbines 3, 4		Auxiliary Boiler	
	Gas	#6 Oil	Gas	#2 Oil	Gas	#2 Oil	Gas	#6 Oil
CO	40.0	5.0	**115.0**	**15.4**	**115**	**15.4**	40.0	5.0
NOX	275.0	42.0	**413.0**	**67.8**	**413.0**	**67.8**	275.0	42.0
SO2	0.6	**109.9**	**0.6**	**40.6**	**0.6**	**40.6**	0.6	109.9

Pollutants	Steam Unit		Turbines 1, 2, 21		Turbines 3, 4		Auxiliary Boiler	
	Gas	#6 Oil	Gas	#2 Oil	Gas	#2 Oil	Gas	#6 Oil
PM10	3.0	**6.7**	**14.0**	**4.8**	**14.0**	**4.8**	3.0	6.7
VOC	1.40	0.76	**12.60**	**4.77**	**12.6**	**4.77**	1.40	0.76

Table 5 Emission Factors (Gas in lb/MMscf and Oil in lb/1000gal. Source: AP-42, 1/95 ed.)

Pollutants	Steam Unit		Turbines 1, 2, 21		Turbines 3, 4		Boiler	
	Gas	#6 Oil	Gas	#2 Oil	Gas	#2 Oil	Gas	#6 Oil
CO	40.0	5.0	**113**	**6.7**	**113**	**6.7**	40.0	5.0
NOX	275.0	42.0	**452**	**97.0**	**452**	**97.0**	275.0	42.0
SO2	0.6	**108.3**	**0.66**	**40.7**	**0.66**	**40.7**	0.6	**108.3**
PM10	3.0	**9.6**	**43**	**8.5**	**43**	**8.5**	3.0	**9.6**
VOC	1.40	0.76	**24.6**	**2.4**	**24.6**	**2.4**	1.40	0.76

The formula used to calculate emissions units burning natural gas is as follows:

Emissions (tpy) = Emission Factor (lb/MMcft) x Net Heat Rate (Btu/KWh) x Max. Generating Capacity (KW)/Heating Value of Fuel (Btu/cft)/10^6 (cft/MMcft) x 8760 (hr/yr)/2000 (lbs/ton)

Table 3 gives the values of the variables used in the above equation. Table 4 summarizes the emission factors used in the above equation. Table 6 gives the emissions in tons per year while burning natural gas. The emissions given here are uncontrolled emissions.

Table 6 Emissions (tpy) While Burning Natural Gas (Emission Factor Source: EPA 450/4-90-003)

Source	**PM_{10}**	**SO_2**	**NO_x**	**CO**	**VOC**	**HAPs**
Steam Unit	10.7	2	983.3	143.0	5	1.6
Turbine #1	16.4	0.7	484.7	135.0	14.8	0.4
Turbine #2	16.4	0.7	484.7	135.0	14.8	0.4
Turbine #3	48.1	2	588.2	395.0	43.3	1.3
Boiler	0.9	0.2	83.5	12.1	0.4	0.1

Total	**92.5**	**5.6**	**2624.4**	**820.1**	**78.3**	**3.8**

The formula used to calculate emissions units burning fuel oil is as follows:

Emissions (tpy) = Emission Factor (lb/gal) x Net Heat Rate (Btu/KWh) x Max. Generating Capacity (KW)/Heating Value of Fuel (Btu/1000 gal)/10^3 (gal/1000 gal) x 8760 (hr/yr)/2000 (lbs/ton)

Table 3 gives values of the variables used in the above equation. Table 4 summarizes the emission factors used in the above equation. Table 7 gives the emissions in tons per year when burning oil. The emissions given here are uncontrolled emissions.

Table 7 Emissions (tpy) While Burning Oil (Emission Factor Source: EPA 450/4-90-003)

Source	PM_{10}	SO_2	NO_x	CO	VOC	HAPs
Steam Unit (Fuel oil #6)	166.7	2718.5	1038.8	123.7	18.8	2.8
Turbine #1 (Fuel oil #2)	41.6	352.2	588.2	133.6	41.4	3.7
Turbine #2 (Fuel oil #2)	41.6	352.2	588.2	133.6	41.4	3.7
Turbine #3 (Fuel oil #2)	121.9	1031.0	1721.7	391.1	121.1	10.91
Turbine #4 (Fuel oil #2)	121.9	1031.0	1721.7	391.1	121.1	10.9112
Turbine #21 (Fuel oil #2)	41.6	352.2	588.2	133.6	41.4	3.7
Boiler (Fuel oil #6)	14.2	230.9	88.2	10.5	1.6	0.2
Total	**549.5**	**6068.0**	**6335.0**	**1317.2**	**386.8**	**35.9212**

Tables 8 and 9 summarize the emissions in tons per year when the source is burning natural gas and oil respectively. These calculations are based on emission factors given in Table 5. Table 10 summarizes the allowable emissions from the different units. The reader is advised to peruse the permit application for HAPs emission calculations. The emissions given in Tables 8 and 9 are uncontrolled emissions. The allowable emissions have been calculated and tabulated in Table 10. These are the allowable emissions under A.A.C. R18-2-703 and A.A.C. R18-2-719.

Table 8 Emissions (tpy) While Burning Natural Gas (Emission Factor Source: AP 42 1/95 ed)

Source	Steam Unit	Turbine #1	Turbine #2	Turbine #3	Turbine #4	Turbine #21	Boiler	Total
CO	143.02	148.07	148.07	440.84	440.84	148.07	12.15	892.16
NOX	983.27	592.29	592.29	1763.38	1763.38	592.29	83.51	4014.73
SO2	2.15	0.86	0.86	2.57	2.57	0.86	0.18	6.63
PM10	10.73	56.35	56.35	167.75	167.75	56.35	0.91	292.09
VOC	5.01	32.24	32.24	95.97	95.97	32.24	0.43	165.87

Table 9 Emissions (tpy) While Burning Oil (Emission Factor Source: AP 42 1/95 ed)

Source	Steam Unit	Turbine #1	Turbine #2	Turbine #3	Turbine #4	Turbine #21	Boiler	Total
CO	123.33	64.91	64.91	193.24	193.24	64.91	10.47	714.99
NOX	1035.97	939.67	939.67	2797.59	2797.59	939.67	87.98	9538.15
SO2	2671.33	394.27	394.27	1173.83	1173.83	394.27	226.87	6428.69
PM10	236.79	82.34	82.34	245.15	245.15	82.34	20.11	994.23
VOC	18.75	23.25	23.25	69.22	69.22	23.25	1.59	228.52

Table 10 Allowable Emissions (tpy)

Source	Steam Unit	Turbine #1	Turbine #2	Turbine #3	Turbine #4	Turbine #21	Boiler
PM	791.03	365.56	365.56	845.89	845.89	365.56	119.77
SOx (Oil)	3672.05	1345.76	1345.76	4006.61	4006.61	1345.76	315.36

IV. COMPLIANCE HISTORY

This section will address Technical Review Question A.9, C.3 and C.4.

A. Inspections

Inspection Date	Type of Inspection	Results
August 7, 1996	Level 2 (FAR No. 15922)	Opacity of the steam generator was less than 5%. Only heat waves were observed to be emanating from the stack.

January 1, 1996	Level 2 (FAR No. 14628)	Opacity of the steam generator was less than 5%. Only heat waves were observed to be emanating from the stack. Only steam generator was operating at 22 MW.
March 30, 1994	Level 2 (FAR No. 10727)	Opacity of the steam generator was less than 5%. Only the steam generator was operating at 20 MW.
July 8, 1992	Level 2 (FAR no. 9595)	Only the steam generator was operating at 21 MW.
November 27, 1991	Level 2 (FAR No. 8876)	Only the steam generator was operating at 38 MW.

B. Excess Emissions

There have been no cases of excess emissions from the Yucca power plant.

C. Previous Emissions Inventory

Year (1996)	
Pollutant	**Actual Emissions**
PM-10	6.90
SOx	26.43
NOx	390.03
VOC	2.76
CO	58.93

D. Testing

This section also addresses Technical Remarks Questions C.3 and C.4.

Date of Test	Equipment Tested	Pollutants Tested	Results
6/21/95	Steam Unit 1	NOx (Method 7E)	Passed

APS conducted a performance test in June 1995 on steam unit 1 for NOX emissions. The average emissions of NOx from this unit was 230.9 ppm or 0.327 lb/MMBtu. This is higher than the allowable emissions for NOx under A.A.C. R18-2-703 which stipulates a limit of 0.20 lb/MMBtu when burning natural gas. However, steam unit 1 is not subject to this requirement since it was placed in commercial operation in 1959 and hence is grandfathered.

E. Compliance Certifications

The Permittee will be required to submit compliance certifications every six months as indicated in Section VII of Attachment "A" of the permit.

V. APPLICABLE REGULATIONS

This section also addresses Technical Remarks Question C.5.

Unit ID	Start-up date	Control Equipment	Applicable Regulations	Standard
Steam Unit 1	3/4/59	None	A.A.C. R18-2-703	SO_2: 1.0 lb/MMBtu (max. 3-hr average) heat input when firing oil. Opacity: < 40% PM: $E = 1.02Q^{0.769}$ lb/hr
Gas Turbine 1	7/1/71	None	A.A.C. R18-2-719 and Yuma SIP R8-1-3-13.A.2.C	SO_2: 0.8% by weight and 1.0 lb/MMBtu heat input when firing oil. Opacity: < 40% PM: $E = 1.02Q^{0.769}$ lb/hr
Gas Turbine 2	7/1/71	None	Same as above	Same as above.
Gas Turbine 3	6/20/73	None	Same as above	Same as above.
Gas Turbine 4	7/9/74	None	Same as above	Same as above.
Gas Turbine 21	12/28/78	None	Same as above	Same as above.
Auxiliary Boiler	1974	None	A.A.C. R18-2-724	SO_2: 1.0 lb/MMBtu (max. 3-hr average) heat input when firing oil. Opacity: < 15% PM: $E = 1.02Q^{0.769}$ lb/hr

VI. PREVIOUS PERMITS AND CONDITIONS

A. Previous Permits

Date Permit Issued	Permit No.	Application Basis
July 21, 1992	0379-95	Renewal of Permit No. 94006-89

This section will also address Technical Review Question B.5, which asks if the source has been constructed according to the prior permit.

The Permittee has been operating the source in compliance with conditions under this permit as could be seen from the inspection reports in Section IV.A of this technical review document.

B. Previous Permit Conditions

This section should list previous installation and operating permit conditions. If the conditions aren't going to be carried over into the Title V permit, state why. If they are, state their location in the permit.

Operating Permit No. 0379-95

Some of the relevant conditions of this permit are as follows:

1. Operate equipment in compliance with all the applicable conditions of A.A.C. R18-2-503, A.A.C. R18-2-519, and A.A.C. R18-2-524.

2. Emission limit on particulate matter emissions from the steam unit, auxiliary boiler, and gas turbines based on heat input.

3. Emission limit on sulfur dioxide emissions of 1.0 lb/MMBtu from the steam unit, auxiliary boiler, and gas turbines.

4. Opacity limit of 40% on gaseous emissions from steam unit, auxiliary boiler, and gas turbines.

5. Performance test equipment including boilers and turbines when that piece of equipment is operated for more than 720 hours/year.

6. Permittee can use only natural gas or fuel oil no.6 in the steam unit and the auxiliary boiler, distillate oil or fuel oil in turbine 4, distillate oil no. 2 in turbine 21, and natural gas or distillate oil no. 2 in turbines 1, 2, and 3.

7. Sulfur content and lower heating value of fuel oil burned in the boilers and turbines to be determined twice per year and any time a shipment of oil is added to the fuel oil storage tank.

8. Average sulfur content, heat content, and quantity of fuel oil burned and heat content and quantity of natural gas burned shall be recored daily.

All the conditions from this permit have been carried over in essence to the Title V permit. The testing requirement has been modified to reflect the requirements of the Arizona Testing Manual. The testing manual requires a major point of emission to be tested every year. Hence the number of hours required for each point of emission to be over 100 tpy threshold was determined and testing required if the hours of operation in a year exceeded this number. The permit condition to test an equipment that has operated for more than 720 hours has been revised so that an equipment is tested based on its ability to be a major point of emission. For the Frame 5 turbines this has been revised to 930 hours of operation per year and for the Frame 7 turbines this has been revised to 310 hours per year of operation.

VII. ADDITIONAL INFORMATION REQUESTED (if applicable)

This section will address Technical Remarks Question A.8

The Permittee submitted the Title V application on February 1, 1995. The application was deemed complete on April 1, 1995. Revised estimates of SO2 emissions were submitted by the source in March 1995. The source was asked to quantify emissions from the storage tanks at the site in November 1995. Source responded to this request for additional information in January 1996. No other requests were made after this date.

VIII. INSIGNIFICANT ACTIVITIES

The following activities have been deemed insignificant (actitivities in redline format will be evaluated for insignificance):

S. No.	Activity
1.	Accidental fires.
2.	Acetylene, butane, and propane torches.

S. No.	Activity
3.	Acid tank vents.
4.	Activities associated with maintenance, repair, or dismantlement of an emission unit or other equipment.
5.	Administration building gas heaters.
6.	Aerosol can usage.
7.	Auxiliary boiler blowdown.
8.	Auxiliary boiler safety relief valves
9.	Bearing cooling water.
10.	Boiler acid wash.
11.	Boiler feed pump hydraulic coating.
12.	Brazing and soldering activities.
13.	Cathodic protection.
14.	Caulking operations.
15.	Caustic tank vents.
16.	Chemical storage tanks.
17.	Chemical storage, hazardous products, and staging area.
18.	Cooling tower chemical additives.
19.	Corona.
20.	Demineralizer regeneration.
21.	Electric motors.
22.	Emissions sampling and associated activities.
23.	Evaporation pond.
24.	Evaporative coolers.
25.	Facilities used for preparing food.

S. No.	Activity
26.	Fire fighting activities and training.
27.	Flammable storage cabinets.
28.	Flares used to indicate danger to the public.
29.	Fuel oil piping systems including: flanges, valves, pump seals, pressure relief valves, and other individual components.
30.	Fugitive dust emissions from the operation of passenger vehicles.
31.	Gas turbine false start drains.
32.	Gas turbine gas vent #1.
33.	Gas turbine gas vent #2.
34.	Gas turbine gas vent #3.
35.	Gas turbine lube oil vents.
36.	Gas turbine starting diesel engines.
37.	Gas yard vents.
38.	General offices activities.
39.	Hot water heater.
40.	Hydraulic system reservoirs.
41.	Individual steam unit ignitors and fuel burner assemblies.
42.	Individual steam unit soot blowers.
43.	Janitorial activities.
44.	Laboratory facilities.
45.	Landscaping equipment.
46.	Lube oil storage area.
47.	Maintenance shop heaters.
48.	Medical activities.

S. No.	Activity
49.	Mercury exhaust hood.
50.	Natural gas fuel piping system including: flanges, valves, pump seals, pressure relief valves, and other individual components.
51.	Normal usage of miscellaneous consumer products.
52.	Oil circuit breakers.
53.	Oil filter draining.
54.	Paint storage area.
55.	Painting.
56.	Pesticide/herbicide activities.
57.	Portable testing equipment and testing activities.
58.	Portable welder.
59.	Production of hot water not related to industrial process.
60.	Pump/motor oil reservoirs.
61.	PVC/ABS pipe welding.
62.	Repair and maintenance of roads or other paved or open areas.
63.	Safety devices, fire extinguishers, and cardox systems.
64.	Sandblasting.
65.	Satellite accumulation barrels.
66.	Septic tanks.
67.	Service water tank and piping.
68.	Small equipment fueling area.
69.	Smoking areas.
70.	Solvent cleaning tank.
71.	Station transformers.

S. No.	Activity
72.	Steam cleaners.
73.	Steam unit air ejector.
74.	Steam unit and gas turbine battery banks.
75.	Steam unit boiler blowdown.
76.	Steam unit drum vents.
77.	Steam unit gas vent.
78.	Steam unit gland steam exhauster.
79.	Steam unit hydrogen scavenging and vents.
80.	Steam unit oil tank vents
81.	Steam unit safety relief vlaves.
82.	Storage tank #1, 100,000 bbls, Fuel oil.
83.	Storage tank #2, 30,000 bbls, Fuel oil.
84.	Storage tank #3, 6000 bbls, Fuel oil.
85.	Storage tank #4, 60,000 bbls, Fuel oil.
86.	Storage tank #5, 100,000 bbls, Fuel oil.
87.	Storage tank #6, 50,000 bbls, Fuel oil.
88.	Storage tank #7, 286 bbls, Fuel oil.
89.	Storage tank #7, 13.7 bbls, Fuel oil.
90.	Storm water drainage area.
91.	Used oil storage area.
92.	Welding.

IX. PERIODIC MONITORING

This section will address Technical Remarks Questions C.1 and C.2. This section will be *continuously updated as we draft permit conditions.*

Emission Limits/Standards

Steam Unit

Opacity: The steam unit is subject to the opacity standard of < 40% under the general visible emissions rule under A.A.C. R18-2-702.B. This unit burns natural gas primarily and is capable of burning fuel oil nos. 4 through 6. Natural gas is a clean burning fuel and usually does not pose a visible emissions problem. The inspection table under Section IV.A of this technical remarks section indicates that there have been no opacity problems with this source.

Particulate matter: The unit is also subject to particulate matter emissions standard under A.A.C. R18-2-703.C.1. This unit burns natural gas primarily and is capable of burning fuel oil nos. 4 through 6. Natural gas is a clean burning fuel and results in negligible particulate matter emissions. The limit under A.A.C. R18-2-703.C.1 imposes a limit of 791 tons per year of PM. From Table 8, the potential to emit is 10.70 tons per year of PM. From Table 9, the potential to emit (when burning oil) is 237 tons per year of PM.

Sulfur dioxide: The steam unit is subject to sulfur dioxide standard under A.A.C. R18-2-703.E.1 since the unit was placed in commercial operation in 1959. This standard applies only when the unit burns oil. There is no standard when the unit burns natural gas. The emission standard in A.A.C. R18-2-703.E.1 imposes a limit of 3672 tons of sulfur dioxide per year. From Table 9, the potential to emit is 2678 tons per year of sulfur dioxide.

Nitrogen oxides: The steam unit was placed in commercial operation on 3/4/1959. The nitrogen oxides standard under A.A.C. R18-2-703.I does not apply to this unit.

Gas Turbine Nos. 1, 2, 3, 4, and 21

Opacity: The turbines are subject to the opacity standard of < 40% under A.A.C. R18-2-719.E. Gas turbine Nos. 1, 2, and 3 burn natural gas primarily and are capable of burning fuel oil no. 2. Gas turbine Nos. 4

and 21 burn fuel oil no. 2 only. Natural gas is a clean burning fuel and usually does not pose a visible emissions problem. Gas turbines 1, 2, and 21 are Frame 5 GE turbines, whereas gas turbines 3 and 4 are Frame 7 GE turbines.

Particulate matter: The units are also subject to particulate matter emissions standard under A.A.C. R18-2-719.C.1. Natural gas is a clean burning fuel and results in negligible particulate matter emissions. The limit under A.A.C. R18-2-719.C.1 imposes a limit of 366 tons per year of PM on each Frame 5 gas turbine. From Table 8, the potential to emit is 56 tons per year of PM. From Table 9, the potential to emit (when burning oil) is 82 tons per year of PM. The limit under A.A.C. R18-2-719.C.1 imposes a limit of 846 tons per year of PM on each Frame 7 gas turbine. From Table 8, the potential to emit is 168 tons per year of PM. From Table 9, the potential to emit (when burning oil) is 245 tons per year of PM.

Sulfur dioxide: The steam unit is subject to sulfur dioxide standard under A.A.C. R18-2-719.F. This standard applies only when the unit burns oil. The emission standard in A.A.C. R18-2-719.F imposes a limit of 1346 tons of sulfur dioxide per year on the Frame 5 turbines and a limit of 4007 tons of sulfur dioxide per yeat on the Frame 7 turbines. From Table 9, the potential to emit is 394 and 1174 tons per year of sulfur dioxide for the Frame 5 and Frame 7 turbines respectively. A.A.C. R18-2-719.J requires reporting of all periods when the sulfur content of the fuel exceeds 0.8 percent by weight and this has been included in the permit as an emission limitation.

Auxiliary Boiler

Opacity: The boiler is subject to the opacity standard of < 15% under A.A.C. R18-2-724.J. This unit burns natural gas primarily and is capable of burning fuel oil nos. 4 through 6. Natural gas is a clean burning fuel and usually does not pose a visible emissions problem.

Particulate matter: The unit is also subject to particulate matter emissions standard under A.A.C. R18-2-724.C.1. This unit burns natural gas primarily and is capable of burning fuel oil nos. 4 through 6. Natural gas is a clean burning fuel and results in negligible particulate matter emissions. The limit under A.A.C. R18-2-724.C.1 imposes a limit of 120 tons per year of PM. From Table 8, the potential to emit is 1 ton per year of PM. From Table 9, the potential to emit (when burning oil) is 20 tons per year of PM.

Sulfur dioxide: The boiler is subject to sulfur dioxide standard under A.A.C. R18-2-724.E. This standard applies only when the unit burns oil. There is no standard when the unit burns natural gas. The emission standard in A.A.C. R18-2-724.E imposes a limit of 315 tons of sulfur dioxide per year. From Table 9, the potential to emit is 227 tons per year of sulfur dioxide.

Cooling Tower

Opacity: The cooling tower is subject to the opacity standard of < 40% under the general visible emissions rule under A.A.C. R18-2-702.B.

Particulate matter: The unit is also subject to particulate matter emissions standard under A.A.C. R18-2-730A.1.

Non-point sources

The standards in Article 6 are applicable requirements for non-point sources. The following sources will be monitored:

1. Driveways, parking areas, vacant lots
2. Unused open areas
3. Open areas (Used, altered, repaired, etc.)
4. Construction of roadways
5. Material transportation
6. Material handling
7. Storage piles
8. Stacking and reclaiming machinery at storage piles

All of these areas must comply with the opacity limitation of 40%. The control measures for these sites include gravel for driveways(1) and native vegetation for unused open areas(2). Most of the other sources require control measures of dust suppressants and/or wetting agents(3-8). Material transportation and storage piles also include covering the material (5 and 7), while stacking and reclaiming includes minimizing fall distance (8).

APS has indicated in the application, that rare instances of open burning may occur. The condition in the permit directs APS to obtain a permit from ADEQ, or the local officer in charge of issuing burn permits.

Other Periodic Activities

Abrasive Sand Blasting

APS has indicated in the permit application that there might be a few occasions on which abrasive sand blasting activities are conducted on-site. R18-2-726 and R18-2-702 (B) are applicable requirements, and as such have to be included in the permit.

Spray Painting

APS has indicated in the permit application that there might be a few occasions on which spray painting activities are conducted on-site. R18-2-727 and R18-2-702(B) are applicable requirements, and as such, have to be included in the permit. R18-2-727(A) and R18-2-727(B) are included in the approved State Implementation Plan (SIP). R18-2-727(C) and R18-2-727(D) are also a part of the approved SIP. They are present in the definitions section of the SIP as R9-3-101.117. EPA approved SIP provision R9-3-527.C is not present in the amended rule. However, R9-3-527.C is an applicable requirement, and is federally enforceable till the current State SIP is approved by the EPA.

Monitoring, Recordkeeping, and Reporting Requirements

Steam Unit

Opacity: As we have seen in the Section under Inspection, natural gas results in low opacity and no monitoring is required. However, when fuel oil is burned, the Permittee is required to monitor and record opacity according to the following schedule:

When fuel is burned continuously for a time period > 48 hours but less than 168 hours, then one EPA Method 9 reading is required.

When fuel is burned continuously for a time period > 168 hours, then for each 168 period one EPA Method 9 reading is required.

Particulate matter: As shown in the Section under Emission Limit/Standards, natural gas combustion results in very low particulate matter emissions and no monitoring is required. However, when fuel oil is burned in the unit, the Permittee is required to monitor particulate matter emissions through engineering calculations using the following information about the fuel found in the contractual agreement with the liquid fuel vendor:

1. Heating value;
2. Ash content; and
3. Fuel firing rate.

Permittee is required to keep on record a copy of the contractual agreement and perform the engineering particulate matter emission calculation whenever there is a change in any of the above in the contractual agreement.

Sulfur dioxide: No monitoring is required while burning natural gas since there is no standard for sulfur dioxide. In addition, the potential to emit sulfur dioxide when combusting natural gas is 2 tons per year because of the negligible sulfur content of natural gas. When fuel oil is burned, the Permittee is required to keep on record fuel supplier certification including the following information:

1. The name of the oil supplier;
2. The sulfur content and the heating value of the fuel from which the shipment came from; and
3. The method used to determine the sulfur content of the oil.

Permittee is required to make engineering calculations for SOx emissions using the information from above according to the following equation:

S (lb/MMBtu) = [(Weight percent of sulfur/100) x Density (lb/gal)]/[(Heating value (Btu/gal)) x (1 MMBtu/1,000,000 Btu)]

Permittee shall perform this calculation for each fuel delivery.

Nitrogen oxides: Although there is no applicable standard for nitrogen oxides, rule A.A.C. R18-2-703.J requires the operation of a CEMS for NOx.

Gas Turbine Nos. 1, 2, 3, 4, and 21

Opacity: As we have seen in the Section under Inspection, natural gas results in low opacity and no monitoring is required. However, when fuel oil is burned, the Permittee is required to monitor and record opacity according to the following schedule:

When fuel is burned continuously for a time period > 48 hours but less than 168 hours, then one EPA Method 9 reading is required.

When fuel is burned continuously for a time period > 168 hours, then for each 168 period one EPA Method 9 reading is required.

Particulate matter: As shown in the Section under Emission Limit/Standards, natural gas combustion results in very low particulate matter emissions and no monitoring is required. However, when fuel oil is burned in the unit, the Permittee is required to monitor particulate matter emissions through engineering calculations using the following information about the fuel found in the contractual agreement with the liquid fuel vendor:

1. Heating value;
2. Ash content; and
3. Fuel firing rate.

Permittee is required to keep on record a copy of the contractual agreement and perform the engineering particulate matter emission calculation whenever there is a change in any of the above in the contractual agreement.

Sulfur dioxide: "Pipeline-quality" natural gas has to conform to standards approved by the Federal Energy Regulatory Commission (FERC). One of the FERC standards limits the sulfur content in the gas to less than 5 grains/100 scf (which is equivalent to 0.017 weight percent of sulfur). Another standard specifies that the heating value be greater than or equal to 967 Btu per cubic foot. EPNG runs the gas turbines with fuel drawn from their pipeline, and therefore it was decided that maintaining a copy of the FERC approved Tariff agreement on-site would be an adequate means of complying with the monitoring requirements for the particulate, opacity and fuel use standards. In addition, the potential to emit sulfur dioxide when combusting natural gas is 1 ton per year and 3 tons per year for Frame 5 and Frame 7 turbines respectively. When fuel oil is burned, the Permittee is required to keep on record fuel supplier certification including the following information:

1. The name of the oil supplier;
2. The sulfur content and the heating value of the fuel from which the shipment came from; and
3. The method used to determine the sulfur content of the oil.

Permittee is required to make engineering calculations for SOx emissions using the information from above according to the following equation:

S (lb/MMBtu) = [(Weight percent of sulfur/100) x Density (lb/gal)]/[(Heating value (Btu/gal)) x (1 MMBtu/1,000,000 Btu)]

Permittee shall perform this calculation for each fuel delivery.

Nitrogen oxides: Although there is no applicable standard for nitrogen oxides, the permittee is required to monitor the dates and hours of operation of the engines for the purposes of testing. According to the Arizona Testing Manual, a major point of emissions is required to be tested every year. The turbines have been determined to cross the major threshold for NOx (100 tpy) according to the following schedule:

1. Frame 5 turbines: When operated for 930 hours/year individually; and
2. Frame 7 turbines: When operated for 310 hours/year individually.

The hours were derived assuming oil is burned in the units. The permit requires the permittee to report the dates and of operation of the turbines semi-annually, during the six months prior to the date of report.

Auxiliary Boiler

Opacity: As we have seen in the Section under Inspection, natural gas results in low opacity and no monitoring is required. However, when fuel oil is burned, the Permittee is required to monitor and record opacity according to the following schedule:

When fuel is burned continuously for a time period > 48 hours but less than 168 hours, then one EPA Method 9 reading is required.

When fuel is burned continuously for a time period > 168 hours, then for each 168 period one EPA Method 9 reading is required.

Particulate matter: As shown in the Section under Emission Limit/Standards, natural gas combustion results in very low particulate matter emissions and no monitoring is required. However, when fuel oil is burned in the unit, the Permittee is required to monitor particulate matter emissions through engineering calculations using the following information about the fuel found in the contractual agreement with the liquid fuel vendor:

1. Heating value;
2. Ash content; and
3. Fuel firing rate.

Permittee is required to keep on record a copy of the contractual agreement and perform the engineering particulate matter emission calculation whenever there is a change in any of the above in the contractual agreement.

Sulfur dioxide: No monitoring is required while burning natural gas since there is no standard for sulfur dioxide. In addition, the potential to emit sulfur dioxide when combusting natural gas is 0.2 tons per year because of the negligible sulfur content of natural gas. When fuel oil is burned, the Permittee is required to keep on record fuel supplier certification including the following information:

1. The name of the oil supplier;
2. The sulfur content and the heating value of the fuel from which the shipment came from; and
3. The method used to determine the sulfur content of the oil.

Permittee is required to make engineering calculations for SOx emissions using the following information from above according to the following equation:

S (lb/MMBtu) = [(Weight percent of sulfur/100) x Density (lb/gal)]/[(Heating value (Btu/gal)) x (1 MMBtu/1,000,000 Btu)]

Permittee shall perform this calculation for each fuel delivery.

Nitrogen oxides: There is no applicable standard and hence no monitoring is required. Also, the unit does not have the potential to be a major emission unit i.e., it cannot emit more than 100 tpy of NOx. Hence, no testing is required.

Nonpoint Sources

The specific non-point sources are listed in the above section. Monitoring and recordkeeping requirements for driveways (1) includes maintaining the gravel, and keeping a log of dates new gravel is added. Unused open areas (2) includes a monthly status of the areas and dates fresh vegetation was added. All other non-point sources (3-8) require a record of the date and type of activity performed, and the type of controls used. Also, monitoring requirements for the applicable open burning rule may be satisfied by keeping all open burn permits on file.

Other Periodic Activities

Other applicable rules are abrasive blasting, spray painting, and solvent cleaning activities. It was decided to prescribe minimal monitoring requirements.